Facility Name: **Chattahoochee Energy Facility**
City: Franklin
County: Heard
AIRS #: 04-13-14900006 Application #: TV-486572

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Introduction

This narrative is being provided to assist the reader in understanding the content of the referenced SIP permit to construct and draft operating permit amendment. Complex issues and unusual items are explained in simpler terms and/or greater detail than is sometimes possible in the actual permit. This permit is being issued pursuant to: (1) Sections 391-3-1-.03(1) and 391-3-1-.03(10) of the Georgia Rules for Air Quality Control, (2) Part 70 of Chapter I of Title 40 of the Code of Federal Regulations, and (3) Title V of the Clean Air Act Amendments of 1990. The following narrative is designed to accompany the draft permit and is presented in the same general order as the permit. This narrative is intended only as an adjunct for the reviewer and has no legal standing. Any revisions made to the permit in response to comments received during the public comment period and EPA review process will be described in an addendum to this narrative.

I. Facility Description

A. Existing Permits

Table 1 below lists the current Title V permit, and all administrative amendments, minor and significant modifications to that permit, and 502(b)(10) attachments.

Table 1: Current Title V Permit and Amendments

Permit/Amendment Number	Date of Issuance	Description
4911-149-0006-V-05-0	January 30, 2018	Title V Renewal

B. Regulatory Status

1. PSD/NSR/RACT

The facility is located in Heard County, which is in attainment for ozone but designated as a contributing county with enhanced monitoring. The combined site is one of the 28 PSD named source category (fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input). Since it has potential emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxide (NOx), volatile organic compounds (VOC), and carbon monoxide (CO) greater than 100 tpy, it is a major source under PSD regulations.

The facility went through a PSD review for NOx, SO_2, CO, VOC and PM/PM_{10} in August 2001 for the construction and operation of the combustion turbine combined-cycle block.

2. Title V Major Source Status by Pollutant

Table 2: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Yes	✓		
PM_{10}	Yes	✓		
$PM_{2.5}$	Yes	✓		
SO_2	Yes	✓		
VOC	Yes	✓		
NO_x	Yes	✓		
CO	Yes	✓		
TRS	N/A			

Table 2: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
H_2S	N/A			
Individual HAP	Yes	✓		
Total HAPs	Yes	✓		

II. Proposed Modification

A. Description of Modification

OPC (Oglethorpe Power Corporation) is proposing the CT (combustion turbine) Upgrades Project involving modifications to the facility's combustion turbines. The project would result in increases in maximum heat input and maximum projected annual air emissions.

The proposed CT Upgrades Project would involve the implementation of two upgrades for OPC Chattahoochee's two combustion turbines: the Thermal Performance Upgrade One (TPU1) and the Low Load Turndown (LLTD) upgrade.

The TPU1 would improve the combustion turbines plant output and heat rate as well as extend the maintenance interval of the units by installing enhanced hardware in the combustion turbines, replacing certain auxiliary hardware components, and adding site-specific control logic optimizations.

New turbine hardware would include combustion chamber components with optimized cooling air reduction, impingement cooled tile holders, the latest ceramic heat shields, metallic heat shields, and burner swirlers with reduced swirl angle. Auxiliary hardware replacements would include the pilot gas flow meter, an advanced combustion dynamics monitoring system, heat resistant ignition cables, blow-off valve actuators, and additional pressure and acceleration measurement instrumentation. These changes would increase the capacity of the facility by approximately 23 MW, with variations for ambient temperatures. The increased capacity would decrease the cost of electricity generation.

The LLTD upgrade would involve the installation of new combustion turbine components and software controls to replace selected equipment and connected accessories to allow for sustained operations at lower operating loads during periods of low demand.

These changes would include the compressor inlet guide vane extended range sensor, ring modification and linearization unit replacement, and the addition of a combustion turbine exhaust metallic heat shield, along with site-specific control logic optimizations. Currently, the facility shuts down periodically during low demand and then restarts when demand increases. The LLTD upgrades would allow the combustion turbines to operate at steady-state minimum loads of approximately 67 MW, with variations for ambient temperatures, while continuing to maintain emission concentrations of NO_X and CO in compliance with the facility's permitted emission limits. As a result, this upgrade would allow the facility to continue to operate with less frequent shutdowns during low demand periods, thereby reducing maintenance and fuel costs associated with cycling through shutdowns and startups.

B. Emissions Change

Table 3: Emissions Change Due to Modification

Pollutant	Is the Pollutant Emitted?	Net Actual Emissions Increase (Decrease) (tpy)	Net Potential Emissions Increase (Decrease) (tpy)
PM	✓	+9.8	+9.8
PM_{10}	✓	+9.8	+9.8
$PM_{2.5}$	✓	+9.5	+9.5
SO_2	✓	+0.9	+0.9
VOC	✓	+1.6	+1.6
NO_x	✓	+36.7	+36.7
CO	✓	+37.6	+37.6
TRS	N/A		
H_2S	N/A		
Individual HAP	✓		
Total HAPs	✓		

OPC is submitting this construction and operating permit application to request authorization to modify and operate the facility's CTs. Since CEF is a major source under the PSD permitting program, emission increases from the proposed project must be evaluated and compared to the significant emission rates (SERs) for regulated pollutants under the PSD program. OPC has evaluated emissions increases of CO, NO_x, particulate matter (PM), total particulate matter with an aerodynamic diameter of less than 10 microns (PM_{10}), total particulate matter with an aerodynamic diameter of less than 2.5 microns ($PM_{2.5}$), greenhouse gases (GHG) in terms of carbon dioxide equivalents (CO_2e), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and VOC resulting from the proposed project for comparison to their respective PSD SERs to determine whether PSD permitting is required, as shown in

Table 4.[1] As illustrated in Table 4, the project emissions increases do not exceed the SERs for any pollutant. Accordingly, neither PSD nor NNSR review is required. Detailed emission calculations can be found in Appendix B of the application.

[1] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, lists the lead (Pb) emission factor for natural gas turbines as ND (no detect); therefore, Pb emissions increases for the proposed project were not evaluated.

Table 4: Project Emissions Increases

Pollutant	Units 8A and 8B				Cooling Tower Associated Emissions Increase (tpy)	Total Project Emissions Increase (tpy)	NSR Significant Emission Rate[2] (tpy)	NSR Triggered?
	Baseline Actual Emissions (tpy)	"Could Have Accommodated" Emissions (tpy)	Projected Actual Emissions (tpy)	Project Emissions Increase[1] (tpy)				
NO_X	100.2	116.4	153.1	36.7	-	**36.7**	40	No
CO	19.0	30.0	67.6	37.6	-	**37.6**	100	No
VOC	11.6	13.5	15.1	1.59	-	**1.6**	40	No
PM	69.7	81.1	90.6	9.5	0.31	**9.8**	25	No
PM_{10}	69.7	81.1	90.6	9.5	0.27	**9.8**	15	No
$PM_{2.5}$	69.7	81.1	90.6	9.5	1.5E-03	**9.5**	10	No
SO_2	7.0	8.1	9.1	0.95	-	**0.9**	40	No
H_2SO_4	0.80	0.93	1.0	0.11	-	**0.1**	7	No
CO_2e[3]	1,382,762	1,608,206	1,796,567	188,361	-	**188,361**	75,000	No

1. Project Emissions Increase = (Projected Actual Emissions - Baseline Actual Emissions) - ("Could Have Accommodated" Emissions - Baseline Actual Emissions)
2. 40 CFR 52.21(b)23(i) and Georgia Air Quality Control Rule 391-3-1-.03(8)(c)15
3. NSR permitting for CO_2e is only required if the project emissions increase exceeds the NSR SER of 75,000 tpy and if NSR permitting is triggered for at least one other regulated pollutant.

For purposes of calculating project emissions increases, different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether the sources affected by the proposed project are considered new or existing emission units. Federal rules, 40 CFR 52.21(b)(7)(i) and (ii) define new unit and existing units, and are incorporated by reference in the GRAQC.

As the emission units at CEF have operated for more than two years, the proposed project involves physical or operational changes to existing emission units only – specifically, the facility's combustion turbines. There are no new emission units proposed for installation as part of this project.

Baseline Actual Emissions

The most recent 5-year lookback period was utilized for this analysis. Accordingly, a period of May 2016 to April 2018 was selected as the 2-year (consecutive 24-month) baseline period for all pollutants except for CO, for which the period of August 2015 to July 2017 was selected. Baseline actual emissions data utilized for the NSR analysis for each combined cycle combustion unit can be found in Appendix B of the application.

OPC expects to begin construction of the CEF Upgrades Project on or before December 31, 2022. The selected baseline data are representative of normal operation. Because the representativeness of future (2021-2022) emissions is unknown and could be impacted by factors outside of OPC's control (e.g., fluctuations in fuel prices), the selected baseline data are approved by the Division under GRAQC 391-3-1-.02(7)(a)2.(i)(I) provided that construction of the CT Upgrades Project begins on or before December 31, 2022. Per the new Conditions in 7.14 of this permit, in order to begin construction after December 31, 2022, OPC would first be required to update the PSD applicability test and submit such information to EPD.

Projected Actual Emissions

Projected actual emissions for the modified equipment were determined for use in the NSR analysis, based on the highest projected level of actual annual utilization of the modified combustion turbine systems in the ten years following the project (at 30.2 x 10^6 MMBtu/yr total for both CCCTs), and estimated actual emission factors derived from facility operations, as summarized in

Table 5.

Table 5. Criteria Pollutant Projected Actual Emission Factors for CCCT Units

Pollutant	Emission Factor (lb/MMBtu)
VOC[1]	1.00E-03
$PM_{10}/PM_{2.5}$[2]	6.00E-03
SO_2[3]	6.00E-04
NO_X[4]	1.01E-02
CO[4]	4.48E-03
H_2SO_4[5]	6.89E-05
CO_2[6]	118.86
CH_4[7]	2.20E-03
N_2O[7]	2.20E-04
CO_2e[7]	118.98

1. VOC emissions were based on the most recent facility compliance testing data. The total VOC emission factor was calculated as the sum of the 2005 VOC as CH_4 (Method 25A) test results and the 2003 formaldehyde (Method 0011) test results. A 10% safety factor was conservatively applied to the stack test results. The emissions concentrations (ppm @ 15% O_2) were converted to emission factors (lb/MMBtu) using the following equation:

$$\text{lb/MMBtu} = (C_{gas,\ VOC\ as\ CH4} * MW_{VOC\ as\ CH4} + C_{gas,\ HCHO} * MW_{HCHO}) * Fd * 2.59E\text{-}9 * 20.9 / (20.9 - \%O_2)$$

where:

$C_{gas,\ VOC\ as\ CH4}$ =	0.596	ppmv, maximum VOC as CH_4 test result for either unit at any load
$MW_{VOC\ as\ CH4}$ =	16.043	lb/lb-mol, molecular weight of CH_4
$C_{gas,\ HCHO}$ =	0.061	ppmv, maximum HCHO test result for either unit at any load
MW_{HCHO} =	30.026	lb/lb-mol, molecular weight of HCHO
Fd =	8,710	dscf/MMBtu, natural gas fuel factor from 40 CFR 60, Method 19, Table 19-2
$\%O_2$ =	15	%, corrected basis for exhaust gas O_2 content

2. PM emissions are based on the average of the 2003 compliance testing results for units 8A (0.0069 lb/MMBtu) and 8B (0.0051 lb/MMBtu). The 2003 testing was inclusive of both the filterable and condensable portions of PM. It was conservatively assumed all PM is less than 2.5 microns in diameter (i.e., $PM_{2.5} = PM_{10}$ = PM).

3. SO_2 emissions were estimated using the default SO_2 emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.1, consistent with the methodology used to report the facility's SO_2 emissions under the CAMD programs.

4. H_2SO_4 emissions were calculated assuming a 7.5% conversion of SO_2 to H_2SO_4, consistent with the facility's initial November 2000 PSD permit application.

4. The projected actual NO_X and CO emission rates were conservatively based on the maximum of the monthly average emission rates (monthly emissions divided by monthly heat input) during the 24-month baseline period for each pollutant.

5. CO_2 emissions were calculated in accordance with 40 CFR 75, Appendix G, Equation G-4 using the F-factor for natural gas, consistent with the methodology used to report the facility's CO_2 emissions under the CAMD programs and the EPA GHG reporting rule.

6. CH_4 and N_2O emission factors for natural gas combustion are from 40 CFR 98, Subpart C, Table C-2, converted from kg to lb, consistent with the methodology used to report the facility's emissions under the EPA GHG reporting rule.

7. CO_2e was calculated as the sum of the emission factor for each GHG pollutant multiplied by that pollutant's global warming potential (GWP). GWPs were taken from 40 CFR 98, Subpart A, Table A-1:

CO_2:	1
CH_4:	25
N_2O:	298

CCTT HAP Emission Factors

HAP and toxic air pollutant (TAP) emissions are evaluated from each CCCT using AP-42 based emission factors and vendor based information, as appropriate. Details regarding the estimation of HAP/TAP emissions can be found in Appendix C of the application.

Cooling Tower Emission Factors

Cooling tower emissions, as found in Appendix B of the application, are calculated based on a vendor based drift rate, and facility records of the Total Dissolved Solids (TDS) concentration present in the waters processed at the cooling tower. This data is relied upon using emission estimation methods for cooling towers outlined in *Calculating Realistic PM_{10} Emissions from Cooling Towers* by Joel Reisman and Gordon Frisbie, 2002, to estimate potential emissions from the facility cooling towers.

Insignificant Emission Sources

The facility has other small insignificant sources of emissions (e.g., fugitive piping leaks, roads, etc.) at the facility which are not quantified within the potential to emit estimates within the application.

Could Have Accommodated Emissions

The "could have accommodated" emissions for this project are based on consideration of the "Georgia Pacific memo" and subsequent correspondence with U.S. EPA, indicating that a maximum 30-day period can be utilized to demonstrate emissions that "could have been accommodated" by a source during the respective baseline period.[2] Additional conservative assumptions were applied to the 30-day maximum period technique as outlined in the referenced Georgia Pacific memo.

Specifically, application of an additional seasonal variation was relied upon for this analysis. The maximum 30-day period from each season was evaluated and used to evaluate total emissions for the entire seasonal period. Seasonal breakdowns were evaluated as follows;

Spring: March – May
Summer: June – August
Fall: September – November
Winter: December – February

Emissions that were excluded using this methodology are necessarily unrelated to the proposed project as they are based on existing capacity and actual data from the selected baseline period.

Additional data regarding the "could have been accommodated" analysis is included in Appendix B of the application.

Associated Emissions Increases

In addition to the emission increases from new or modified units, emission increases from associated emission units that may realize an increase in emissions due to a project must be included in the assessment of the project emissions increases. CEF anticipates that the modifications to and increased utilization of the combustion turbines would result in an associated increase in drift loss and, therefore, air emissions from the facility's cooling tower. As such, an associated emissions increases are included in this analysis for the cooling towers.

Toxic Impact Analysis

A toxic impact analysis was performed and included in the application in Appendix C. The Division reviewed the analysis and agrees that the result of the analysis is that the impacts of all TAP from CEF are well below the respective annual, 24-hour, and 15-minute AACs.

[2] https://www.epa.gov/nsr/response-georgia-pacific-use-demand-growth-exclusion-projected-actual-emissions

C. PSD/NSR Applicability

The facility is an existing PSD major source, as it has potential emissions of multiple regulated criteria pollutants exceeding the major source threshold of 100 tpy.[3] As a result, new construction or modifications that result in emissions increases for criteria pollutants are potentially subject to PSD permitting requirements.

Additionally, the facility is located in a county specified by the Division as subject to GRAQC 391-3-1-.03(8)(c)15, which addresses additional provisions for electrical generating units in the areas contributing to the Atlanta ozone nonattainment area. This state regulation specifies that certain NNSR provisions are potentially applicable when permitting new construction or modifications at any electrical generating unit that is located in a listed contributing county and that has facility-wide potential NO_X emissions exceeding 100 tpy.[4] As the CEF's potential NO_X emissions exceed 100 tpy, the facility is a major source for NO_X emissions under this state regulation. Therefore, applicability of the proposed project to these NNSR permitting provisions was assessed.

As the facility is classified as a major source for PSD, if the proposed project meets the definition of a *major modification*, then the full PSD permitting requirements apply. For all PSD-regulated pollutants other than CO_2e, PSD permitting is required if the emissions increase of a specific pollutant exceeds that pollutant's PSD SER. For CO_2e, PSD permitting is only required if the emissions increase exceeds the SER for CO_2e and the project is already undergoing PSD permitting for at least one other PSD-regulated pollutant.[5] For NO_X, certain NNSR provisions are required if the emissions increase exceeds the applicable NNSR SER of 40 tpy.[6] As illustrated in Table 4, the project emissions increases do not exceed the SERs for any pollutant. Accordingly, neither PSD nor NNSR review is required.

IV. Regulated Equipment Requirements

A. Brief Process Description

OPC (Oglethorpe Power Corporation) is proposing the CT (combustion turbine) Upgrades Project involving modifications to the facility's combustion turbines. The project would result in increases in maximum heat input and maximum projected annual air emissions.

[3] Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr input (which includes combined cycle natural gas plants) are on the "List of 28" named source categories which are subject to a lower major source threshold for criteria pollutants of 100 tpy.

[4] GRAQC 391-3-1-.03(8)(c)15(i)

[5] 40 CFR 52.21(b)(49)(iii) as incorporated by reference in the GRAQC

[6] GRAQC 391-3-1-.03(8)(c)15(ii)

B. Equipment List for the Process

Emission Units		Applicable Requirements/Standards	Air Pollution Control Devices	
ID No.	Description		ID No.	Description
CT8A	Combustion Turbine Unit 8A Siemens-Westinghouse Model V84.3a2 Capacity = 177 MW (ISO) Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60 Subpart GG 40 CFR 60, Subpart KKKK*** 40 CFR 63 Subpart A 40 CFR 63 Subpart YYYY Acid Rain CSAPR 391-3-1-.02(2)(b)1. 391-3-1-.02(2)(g)2.	LC8A SC8A CO8A	Dry Low NOx Burner SCR Catalytic Oxidation**
DB8A	HRSG Duct Burner for Turbine 8A Capacity = 95 MMBtu/hr Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60 Subpart GG 40 CFR 60 Subpart KKKK*** Acid Rain 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)2.	LD8A SC8A CO8A	Dry Low NOx Burner SCR Catalytic Oxidation**
CT8B	Combustion Turbine Unit 8B Siemens-Westinghouse Model V84.3a2 Capacity = 177 MW (ISO) Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60 Subpart GG 40 CFR 60, Subpart KKKK*** 40 CFR 63 Subpart A 40 CFR 63 Subpart YYYY Acid Rain CSAPR 391-3-1-.02(2)(b)1. 391-3-1-.02(2)(g)2.	LC8B SC8B CO8B	Dry Low NOx Burner SCR Catalytic Oxidation**
DB8B	HRSG Duct Burner for Turbine 8B Capacity = 95 MMBtu/hr Installed in 2002: 2020 Upgrades	40 CFR 52.21 40 CFR 60 Subpart A 40 CFR 60 Subpart GG 40 CFR 60 Subpart KKKK*** Acid Rain 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)2.	LD8B SC8B CO8B	Dry Low NOx Burner SCR Catalytic Oxidation**

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards are intended as a compliance tool and may not be definitive.

** Catalytic Oxidation System was not required as a result of CO BACT review done in August 2001.

*** Reflects the regulatory applicability for the Combustion Turbines (CT8A, CT8B) and Duct Burners (DB8A, DB8B) following the completion of the Thermal Performance Upgrade One (TPU1) upgrade.

C. Equipment & Rule Applicability

Combustion Turbines CT8A and CT8B

Federal Rule Standards

40 CFR 60 Subpart GG – "Standards of Performance for Stationary Gas Turbines"

Presently, the combustion turbines at CEF are subject to NSPS Subpart GG. However, upon completion of the proposed modifications, the combustion turbine systems will be subject to the more recently promulgated standards for Stationary Combustion Turbines under NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(b) (NSPS Subpart KKKK), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, NSPS Subpart GG will no longer apply to the facility's combustion turbines following the proposed project.

40 CFR 60 Subpart KKKK – Stationary Combustion Turbines

NSPS Subpart KKKK, *Standards of Performance for Stationary Combustion Turbines*, applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, and were constructed, reconstructed, or modified after February 18, 2005.[7] CEF consists of two natural gas-fired turbines, each of which was constructed prior to 2005 and has a heat input capacity exceeding 10 MMBtu/hr. To determine if the turbines will be subject to NSPS Subpart KKKK following the proposed project, it is necessary to ascertain if a "modification" per the NSPS has occurred. For purposes of NSPS, a modification is defined as:[8]

…any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

More specifically, for an existing electric utility steam generating unit:[9]

No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification…provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

The CT Upgrades Project will result in an increase in the hourly heat input capacity for the combustion turbines. OPC has presumed that an increase in the amount of an air pollutant regulated by NSPS Subpart KKKK could occur on a short-term (hourly) basis. Therefore, once the proposed modifications are complete, the CEF combustion turbines will be subject to NSPS

[7] 40 CFR 60.4305(a), (b)

[8] 40 CFR 60.2

[9] 40 CFR 60.14(h)

Subpart KKKK. Pursuant to 40 CFR 60.4305(a), the associated HRSG and duct burners will also be subject to NSPS Subpart KKKK.

Per 40 CFR 60.4305(b), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. HRSGs and duct burners regulated under NSPS Subpart KKKK are also exempt from the requirements of NSPS Subparts Da, Db, and Dc.

Emission Limits

Per Table 1 to NSPS Subpart KKKK, a modified combustion turbine is subject to NO_X emission limits depending on the type of fuel combusted and the heat input at peak load. For modified combustion turbines firing natural gas with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2 or 0.43 lb/MWh useful output. NSPS Subpart KKKK also includes, for units greater than 30 MW output, a NO_X limit of 96 ppm at 15% O_2 or 4.7 lb/MWh useful output for turbine operation at ambient temperatures less than 0 °F and turbine operation at loads less than 75% of peak load.[10] Compliance with the NO_X emission limit is determined on a 30 unit operating day rolling average basis.[11] The combustion turbines and duct burners are presently subject to a NO_X BACT limitation of 3.0 ppm at 15% O_2, 4-hour average per Condition 3.3.6.a of the existing Title V operating permit.

SO_2 emissions from combustion turbines located in the continental U.S. are limited to 0.9 lb/MWh gross output (or 110 ng/J), or the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.[12]

Monitoring and Testing Requirements

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

NO_X Compliance Demonstration Requirements

The combustion turbine systems presently employ a continuous emission monitoring system (CEMS) for NO_X per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Pursuant to 40 CFR 60.4340(b)(1) and 40 CFR 60.4345, CEF can rely on its existing NO_X CEMS installed and certified according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NSPS Subpart KKKK NO_X emission limits. Sources demonstrating compliance with the NO_X emission limit via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[13] Initial compliance with the NO_X emission limit will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial relative accuracy test audit (RATA) required pursuant to 40 CFR 60.4405 to the

[10] Table 1 to Subpart KKKK of Part 60

[11] 40 CFR 60.4350(h), 40 CFR 60.4380(b)(1)

[12] 40 CFR 60.4330(a)(1) or (a)(2), respectively

[13] 40 CFR 60.4340(b), 40 CFR 60.4405

NO_X emission limit under this subpart.[14] NO_x emissions must be measured after the duct burner rather than directly after the turbine.

SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by the Division;[15] however, CEF elects to opt out of this provision of the rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2.[16] This demonstration can be made using one of the following methods:

- By using a purchase contract specifying that the fuel sulfur content for the natural gas is less than or equal to 20 grains of sulfur per 100 standard cubic feet and results in potential emissions not exceeding 0.060 lb/MMBtu; or
- By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

CEF is currently required to monitor the sulfur content of the natural gas burned in the combustion turbines and duct burners through submittal of a semiannual analysis of the gas by the supplier or the facility to demonstrate that the sulfur content does not exceed its excursion threshold of 0.27 grains per 100 standard cubic feet.[17] This sulfur content analysis by the supplier or CEF satisfies the sulfur content demonstration requirement of 40 CFR 60.4365. Therefore, continued compliance with this existing permit condition will guarantee compliance with the NSPS Subpart KKKK sulfur monitoring requirement.

Initial Notification

Per 40 CFR 60.7(a)(4), Permit Application No. TV-486572 serves as the required notification for any physical or operational change to an existing facility which qualifies as an NSPS modification.

40 CFR 60 Subpart TTTT – Greenhouse Gas Emissions for Electric Generating Units

NSPS Subpart TTTT, *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, applies to any fossil fuel fired steam generating unit, Integrated Gasification Combined Cycle (IGCC) unit, or stationary combustion turbine constructed after January 8, 2014 or reconstructed after June 18, 2014, and to any steam generating unit or IGCC modified after June 18, 2014, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid.[18] The existing CCCT

[14] 40 CFR 60.4405(c)

[15] 40 CFR 60.4370(b) and (c)

[16] 40 CFR 60.4365

[17] Permit No. 4911-149-0006-V-05-0, Conditions 5.2.3, 5.2.4, 6.1.7.c.i.

[18] 40 CFR 60.5509(a)

generating units for CEF each have peak heat inputs greater than 250 MMBtu/hr and serve a generator greater than 25 MW. Therefore, the CCCT generating units (including the duct burners) could potentially be subject to the provisions of NSPS TTTT.

With respect to stationary combustion turbines, NSPS Subpart TTTT applies only to units that commenced construction or reconstruction after the specified dates, not modification. "Reconstruction" is defined under 40 CFR 60 Subpart A as the replacement of components of an existing affected facility such that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable, entirely new affected facility that is technologically and economically capable of complying with the applicable standards.[19] The total cost of the TPU1 and LLTD upgrades is well under 50% of the cost for two comparable new units. As the combustion turbines at CEF are existing units and the proposed project does not meet the reconstruction definition, the modifications to the turbine systems will not trigger applicability of NSPS Subpart TTTT requirements.[20]

<u>40 CFR 63 Subpart YYYY – "National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines"</u>

The combustion turbines are also subject to 40 CFR 63 Subpart YYYY, per 40 CFR 63.6085(a) and (b), because the turbines are located a major source (the combined site) of single and combined HAP emissions. Per 40 CFR 63.6090(a)(1), both of Combustion Turbines CT8A and CT8B are existing affected sources. According to 40 CFR 63.6090(b)(4), existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part.

Reconstruction for the purposes of the NESHAP in 40 CFR 63 is defined as:[21]

The replacement of components of an affected or a previously nonaffected source to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source;

The proposed project will not exceed more than 50% of the cost of two comparable new combustion turbines. Therefore, the combustion turbines at CEF will remain existing sources under Subpart YYYY following the proposed project.

[19] 40 CFR 60.15

[20] 40 CFR 60.5509(a)

[21] 40 CFR 63.2

Initial Notification

No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

40 CFR 64, Compliance Assurance Monitoring (CAM)

Under 40 CFR 64, Compliance Assurance Monitoring (CAM), facilities are required to prepare and submit monitoring plans for certain emissions units as part of Title V operating permit applications. The CAM plans are intended to provide an on-going and reasonable assurance of compliance with emission limits for units equipped with air pollution control devices. Pursuant to 40 CFR 64.2(b)(1)(vi), emission limits for which a Part 70 Permit specifies a continuous compliance determination method are exempt from CAM requirements. Since Condition 5.2.1 of the facility's permit requires the operation of a NO_X and CO CEMS for both CCCT stacks, the Division has previously determined that the emission units are exempt from CAM. Therefore, no CAM documentation was included with the permit application.

The combustion turbines (ID Nos. CT8A and CT8B) and duct burners (ID Nos. DB8A and DB8B) are controlled by the selective catalytic reduction (SCR) to control NOx emissions in order to comply with the NOx BACT limit. Although the combustion turbines and duct burners are controlled by a catalytic oxidation system to reduce CO emissions, the catalytic oxidation system was not required as the CO BACT in the 2001 PSD review.

Federal Rule – Acid Rain Program

Applicability: The Acid Rain Regulations apply to the CT/HRSG system because it has a nameplate capacity greater than $25MW_e$ and it is to supply electricity for sale, whether wholesale or retail.

This facility is subject to requirements in Title IV of the 1990 Clean Air Act Amendment (CAAA). The CT/HRSG system is subject to 40 CFR 72 (permits), 73 (sulfur dioxide), and 75 (monitoring). It is not subject to the nitrogen oxide provisions (40 CFR 76) of the Acid Rain regulations because it does not have the capability to burn coal.

Emission Standard: No SO_2 allowances are allocated up front to the facility, by the Acid Rain Regulations. As such, OPC will need to acquire SO_2 allowances in amounts equal to their annual SO_2 tonnage. Annual SO_2 emissions could be as high as 10.7 tpy for Power Block 8.

NOx emissions are not limited by the Acid Rain Regulation since the units are not classified as coal-fired utility boilers.

Federal Rule – Cross-State Air Pollution Rule (CSAPR)

The CAIR, 40 CFR 96, called for reductions in SO_2 and NO_X emissions by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NO_X SIP Call / NO_X Budget program, and the name of 40 CFR 96 (NOX Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NO_X.

The CSAPR was developed to require affected states to reduce emissions from power plants that contribute to ozone and/or particulate matter emissions. Following legal challenges, CSAPR replaced CAIR and began Phase 1 implementation on January 1, 2015 for annual programs and May 1, 2015 for the ozone season program. Phase 2 implementation began on January 1, 2017 for annual programs and May 1, 2017 for ozone season programs.

Therefore, since CSAPR is currently effective, potential applicability is evaluated against the CSAPR Program and not CAIR. CSAPR applicability is found in 40 CFR 97.404 and definitions in 40 CFR 97.402 and implemented via Georgia EPD through GRAQC 391-3-1-.02(12) – (13). Georgia is subject to CSAPR programs for both fine particles (SO2 and annual NOX) and ozone (ozone season NOX).

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR 97.402. In general, CSAPR regulates fossil-fuel-fired boilers and combustion turbines serving, on any day starting November 15, 1990 or later, an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale. OPC Chattahoochee's CCCTs are affected sources under this regulation, and the proposed project will not alter any applicable requirements or compliance options of CSAPR to the facility's operations. OPC Chattahoochee will continue to maintain sufficient allowances under CSAPR for its operations.

Duct Burners DB8A and DB8B

Federal Rule Standards

40 CFR 60 Subpart Dc – "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units"

Presently, the Duct Burners DB8A and DB8B at CEF are subject to NSPS Subpart Dc. They were constructed after June 9, 1989; and each has a maximum design heat input rate between 10 and 100 MMBtu/hr (95 MMBTU/hr), However, upon completion of the proposed modifications, the combustion turbine systems will be subject to NSPS Subpart KKKK. Pursuant to 40 CFR 60.4305(a), "Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners." Under 40 CFR 60.4305(b), "Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part."

40 CFR 63 Subpart DDDDD – "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters"

Since the combined site is major under Title V of 1990 CAAA for single and combined HAP emissions, the duct burners could potentially be subject to 40 CFR 63 Subpart DDDDD. However, duct burners meet the definition of a waste heat boiler, which is excluded from the definition of a boiler. Since the duct burners are not boilers, they are not subject to 40 CFR 63 Subpart DDDDD.

The rule defines a "boiler" as an enclosed device using controlled combustion to recover thermal energy in the form of steam and/or hot water. The combustion turbines at the OPC Chattahoochee use the thermal energy of natural gas directly through combustion and without use of steam or hot water. Therefore, they do not fall within the definition of a "boiler" and are not subject to the rule.

GA State Rule Standards

Combustion Turbines CT8A and CT8B

The combustion turbines are subject to the visible emission limit (40 percent opacity) specified in Georgia Air Quality Control Rule 391-3-1-.02(2)(b) "Visible Emissions," and the fuel sulfur content limit specified in Georgia Air Quality Control Rule 391-3-1-.02(2)(g) "Sulfur Dioxide." Note that the GA Rule (b) visible emission limit is subsumed by the PM BACT limit (10 percent opacity), while the GA Rule (g) fuel sulfur content limit is subsumed by the fuel requirement specified in Conditions 3.3.2 and 3.3.12. Since the turbines fire exclusively on natural gas, and natural gas is considered a clean fuel, compliance with both GA Rule (b) and (g) limits is expected.

Duct Burners DB8A and DB8B

The duct burners are subject to Georgia Air Quality Control Rule 391-3-1-.02(2)(d) "Fuel Burning Equipment." Since they were constructed after 1972, Georgia Rule 391-3-1-.02(2)(d)3. limits the opacity of the emissions from the duct burners to twenty (20) percent. Also, the allowable PM emission rates from the duct burners are specified by Georgia Rule 391-3-1-.02(2)(d)2.(ii), as follows:

$P = 0.5 * (10 / R)^{0.5}$

Where P equals the allowable PM emission rate in pounds per million BTU and R equals the heat input in million BTUs per hour.

The GA Rule (d) PM and visible emission limits are subsumed by the PM BACT limits in Conditions 3.3.6c. and e. Since the duct burners fire exclusively on natural gas, and natural gas is considered a clean fuel, compliance with both limits are expected.

The duct burners are also subject to the fuel sulfur content limit specified in GA Rule (g). Since the duct burners fire exclusively on natural gas, and natural gas is considered a clean fuel, compliance with GA Rule (g) 2.5-percent fuel sulfur content limit is expected.

D. Modified and New Permit Conditions

Condition 3.3.2 limits the combustion turbines to fire only natural gas. Subpart GG and Subpart KKKK citation added.

Condition 3.3.3 limits the duct burners to fire only natural gas. Subpart GG and Subpart KKKK citation added.

Condition 3.3.11 subjects the combustion turbines (ID Nos. CT8A and CT8B) to 40 CFR 60 Subpart A and Subpart GG. This condition will be replaced with New Condition 3.3.15 following completion of the Thermal Performance Upgrade One (TPU1) project.

Condition 3.3.12 includes the NSPS Subpart GG fuel sulfur content limit. This condition will be replaced with New Condition 3.3.16 following completion of the Thermal Performance Upgrade One (TPU1) project.

Condition 3.3.13 subjects the duct burners (ID Nos. DB8A and DB8B) to 40 CFR 60 Subpart A and Subpart Dc. This condition will be replaced with New Condition 3.3.15 following completion of the Thermal Performance Upgrade One (TPU1) project.

New Condition 3.3.15 subjects the combustion turbines and duct burners (ID Nos. CT8A, CT8B, DB8A, and DB8B) to 40 CFR 60 Subpart A and Subpart KKKK. This condition will become applicable following completion of the Thermal Performance Upgrade One (TPU1) project.

New Condition 3.3.16 includes the NSPS Subpart KKKK fuel sulfur content limit. This condition will become applicable following completion of the Thermal Performance Upgrade One (TPU1) project.

New Condition 3.3.17 includes the NSPS Subpart KKKK NOx limits. This condition will become applicable following completion of the Thermal Performance Upgrade One (TPU1) project.

V. Testing Requirements (with Associated Record Keeping and Reporting)

Condition 4.1.3f updated Method 5 and/or 201A.

Condition 4.2.1 state the initial testing requirements for PM emissions.

Condition 4.2.2 state the initial testing requirements for NOx emissions.

VI. Monitoring Requirements (with Associated Record Keeping and Reporting)

Condition 5.2.1 Subpart GG and Subpart KKKK citation added.

Condition 5.2.3 was modified to include the requirements of 40 CFR 60 Subpart KKKK.

Condition 5.2.4 was deleted since it is no longer needed as the requirement has been included in Condition 5.2.3.

Condition 5.2.5 was modified to no longer apply following completion of the Thermal Performance Upgrade One (TPU1) project, since the requirements of 40 CFR 60 Subpart GG will no longer be applicable.

New Condition 5.2.9 was added to include the requirements of 40 CFR 60 Subpart KKKK following completion of the Thermal Performance Upgrade One (TPU1) project.

VII. Other Record Keeping and Reporting Requirements

New Conditions 6.1.7a.i. and 6.1.7a.ii. were added to state excess emissions as defined in 40 CFR 60 Subpart KKKK following completion of the Thermal Performance Upgrade One (TPU1) project.

Condition 6.1.7b.i. was modified to include the references to Part 52.

Condition 6.1.7b.ix was modified to no longer apply following completion of the Thermal Performance Upgrade One (TPU1) project.

Condition 6.1.7d.vii was modified to include the references to 40 CFR 60 Subpart KKKK as well as references to of 40 CFR 60 Subpart GG.

Condition Nos. 6.2.11, 6.2.12, and 6.2.13 require that the facility calculate and report their total actual emissions for the 10 years following the combustion turbine upgrade projects to show compliance with the actual to predicted-actual emissions calculations that demonstrate NSR non-applicability (recordkeeping requirements from GA Rule 391-3-1-.02(7)(b)15.(i)(III) and (V)). They are requested to report the unit's annual emissions of any regulated NSR pollutant from the facility that could increase as a result of the modifications, from each combined combustion turbine and duct burner stack specified in Condition 3.3.1 during the calendar year.

Condition 6.2.14 contains the notification requirements of the return of combustion turbines CT8A and CT8B to normal operations after completion of the Thermal Performance Upgrade One (TPU1) project or the Low Load Turndown (LLTD) project.

New Condition No. 7.14.1 contains the NSR recordkeeping requirements of GA Rule 391-3-1-.02(7)(b)15.(i)(I). Per New Condition 7.14.2, OPC must update these records and provide a copy to EPD if construction of the CT Upgrades Project does not commence on the expected schedule of on or before December 31, 2022.

VIII. Specific Requirements

A. Operational Flexibility

There are no requests for operational flexibility associated with this modification.

B. Alternative Requirements

There are no alternative requirements associated with this modification.

C. Insignificant Activities

There are no insignificant activities associated with this modification.

D. Temporary Sources

There are no temporary sources associated with this modification.

E. Short-Term Activities

There are no short-term activities associated with this modification.

F. Compliance Schedule/Progress Reports

The company did not indicate any noncompliance issues in its application.

G. Emissions Trading

There are no emissions trading associated with this modification.

H. Acid Rain Requirements/CAIR/CSPAR

This permit modification does not affect the applicability of Acid Rain or CAIR/CSPAR requirements to this facility.

I. Prevention of Accidental Releases

This permit modification does not affect the applicability of Prevention of Accidental Releases requirements to this facility.

J. Stratospheric Ozone Protection Requirements

This permit modification does not affect the applicability of Stratospheric Ozone Protection requirements to this facility.

K. Pollution Prevention

This permit modification does not affect the applicability of Pollution Prevention requirements to this facility.

L. Specific Conditions

Permit Condition 7.14.1 and 7.14.2 are added to include the recordkeeping requirements from GA Rule 391-3-1-.02(7)(b)15.(i)(I) and (II).

Addendum to Narrative

The 30-day public review started on month day, year and ended on month day, year. Comments were/were not received by the Division.

//If comments were received, state the commenter, the date the comments were received in the above paragraph. All explanations of any changes should be addressed below.//